UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
999 18TH STREET - SUITE 500
DENVER, CO 80202-2466
http://www.epa.gov/region08

UNDERGROUND INJECTION CONTROL PROGRAM

FINAL PERMIT

Class II Enhanced Oil Recovery Well
UIC Permit No. WY2866-02130

Well Name: Tribal S-1
Field Name: Steamboat Butte
County & State: Fremont County, Wyoming

issued to:

Marathon Oil Company
1501 Stampede Avenue
Cody, Wyoming 82414-4721

Date Prepared: October 1999

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PART I. AUTHORIZATION TO CONVERT AND OPERATE

Pursuant to the Underground Injection Control Regulations of the U. S. Environmental Protection Agency codified at Title 40 of the Code of Federal Regulations, Parts 124, 144, 146, and 147,

Marathon Oil Company
1501 Stampede Avenue
Cody, Wyoming 82414-4721

is hereby authorized to convert a Tensleep Formation injector to a commingled Nugget, Phosphoria and Tensleep Class II enhanced oil recovery well, known as the:

Tribal S-1
NE/4 of the NE/4
Section 6, Township 3 North, Range 1 West
Fremont County, Wyoming

Injection shall be for the purpose of enhancing oil recovery from the Nugget/Phosphoria/Tensleep Formations so that Marathon Oil Company (Marathon) may continue to economically produce oil from their Steamboat Butte Field, in accordance with conditions set forth herein.

Injection activities shall not commence until the operator has fulfilled all applicable conditions of this permit and has received written authorization from the Director. "Prior to Commencing Injection" requirements are set forth in Part II. Section C. 1. of this permit.

All conditions set forth herein refer to Title 40 §§124, 144, 146, and 147 of the Code of Federal Regulations and are regulations that are in effect on the date that this permit becomes effective.

This permit consists of a total of 39 pages and includes all items listed in the Table of Contents. Further, it is based upon representations made by the permittee and on other information contained in the administrative record.

This permit will be issued for the operating life of the well and will be reviewed by the EPA at least every five (5) years to determine whether action under 40 CFR §144.36 (a) is warranted. The permit will expire upon delegation of primary enforcement responsibility for the UIC Program to the State of Wyoming and/or the Shoshone and Arapaho Tribes, unless that State or Tribes has both authority, and chooses, to adopt and enforce this permit as a State or Tribal permit.

Issued this day of OCT 28 1999.

This permit shall become effective OCT 28 1999.

for Stephen S. Tuber

Kerrigan G. Clough
* Assistant Regional Administrator
Office of Partnerships and
Regulatory Assistance

* NOTE: The person holding this title is referred to as the "Director" throughout this permit

PART II. SPECIFIC PERMIT CONDITIONS

A. WELL CONSTRUCTION/CONVERSION REQUIREMENTS

1. **Casing and Cementing.** The as built construction and conversion details submitted with the application are hereby incorporated into this permit as **Appendix A**, and shall be binding on the permittee. The cement used in the construction and conversion of the well was designed for the life expectancy of the well.

2. **Tubing and Packer Specifications.** Injection tubing and packer shall be designed to prevent injected fluids from coming into contact with the outermost casing string. The packer shall be set at a depth of no more than 100 feet above the top injection perforations. The presence of an annular space between the tubing and the casing allows the casing integrity to be periodically tested, as well as to monitor for leaks in the tubing.

3. **Monitoring Devices.** The operator shall provide and maintain in good operating condition:

   (a) a tap on the injection line between the pump house and the storage tank(s) and the injection well, for collection of a representative sample of injection fluids;

   (b) two (2) one-half (1/2) inch Female Iron Pipe (FIP) fittings with cut-off valves, one at the wellhead on the tubing, and a similar fitting and cut-off valve for the casing/tubing annulus (for attachment of pressure gauges). The operator shall always have in his possession calibrated gauges for the use of their field personnel to monitor these pressures.

   (c) a flow meter with a cumulative volume recorder that is certified for 95 percent accuracy or more throughout the range of injection rates allowed by the permit.

4. **Proposed Changes and Workovers.** The permittee shall give advance notice to the Director, as soon as possible, of any planned physical alterations or additions to the permitted facility. Major alterations or workovers of the permitted well shall meet all conditions as set forth in this permit. A major

alteration/workover shall be considered any work performed which affects casing, packer(s), or tubing. In addition, the permittee shall provide all records of well workovers, logging, or other test data to EPA within sixty (60) days of completion of the activity. **Appendix B** contains samples of the appropriate reporting forms.

Demonstration of mechanical integrity shall be performed within thirty (30) days of completion of workovers/alterations and prior to resuming injection activities, in accordance with Part II. Section C. 2. (a).

5. **Formation Logging and Well Testing.**

   (a) Following the conversion of Tribal S-1, the permittee will determine the **disposal zone pore pressure, (static bottom-hole pressure).**

   (b) A **casing/tubing annulus pressure test** must be performed and witnessed by representative of the EPA prior to commencement of injection. The Tribal S-1 well must pass the test, thereby demonstrating the absence of leaks in the casing, tubing, and packer. Written authorization to inject will be given **subsequent to the well completion and mechanical integrity demonstration**.

   (c) **A Water Injection Profile Log** may be run as soon as stabilized injection pressure has been established. This test will be used to assure no out of zone injection is occurring and may be used as a tool for monitoring the waterflood injection zone efficiency for secondary recovery.

6. **Postponement of Conversion.** If the well is not converted to injection status within one (1) year from the effective date of this permit, the authorization to convert and operate will automatically expire, unless the permittee requests and is granted an extension. The request shall be made to the Director in writing, and shall state the reasons for the delay in conversion/construction, and confirm the protection of all USDWs. The extension under this section may not exceed one (1) year. Once authorization to convert and inject expires under this part, the full permitting process, including opportunity for public comment, must be repeated before authorization to construct/convert and operate will be reissued.

B. CORRECTIVE ACTION

The applicant submitted the required 1/4 mile area of review information with the permit application. Listed are eight (8) wells; six (6) producing wells, (1-Frontier, 3-Nugget, 2-Tensleep), one (1) Class II permitted and commingled well (Phosphoria/Tensleep), and one (1) Class II Rule Authorized injection well (subject well). In each of these wells, the production/wellbore annulus is cemented from the top of the Frontier, upward and several hundred feet into the overlying Cody shale (confining zone) and the underlying thick (527 feet) Mowry shale. All wells are adequately constructed to preclude USDW contamination via injection into the Nugget, Phosphoria and Tensleep Formations; therefore, the only corrective action required (perforate and block squeeze Phosphoria) is on the recently permitted well, Tribal C-28. **<u>This corrective action must be completed and approved prior to commencing injection</u>**.

C. WELL OPERATION

1. **<u>Prior to Commencing Injection.</u>** Injection operations may not commence until the permittee has complied with (a), and (b), as follows:

   (a) Conversion is complete, and the permittee has submitted a **Well Rework Record (Form 7520-12)** as found in **Appendix B**; and **<u>permittee has submitted well rework records for the Tribal C-28 well showing successful completion of the required corrective action</u>**; and

      (i) The Director has inspected or otherwise reviewed the new injection well and finds it is in compliance with the conditions of the permit; or

      (ii) The permittee has not received notice from the Director of his or her intent to inspect or otherwise review the new injection well within thirteen (13) days of the date the Director receives the Well Completion Report in paragraph (a) of this permit condition in which case prior inspection or review is waived and the permittee may commence injection. (Note: However, item (b) below must also be satisfied).

(b) The permittee completes the requirements for Formation Logging and Well Testing (Part II, Section A. 5. above) and demonstrates that the well (Tribal S-1) has mechanical integrity in accordance with 40 CFR §146.8 and Part II, Section C. 2. below, and has received notice from the Director that such demonstration is satisfactory.

2. **Mechanical Integrity Demonstration** The permittee is required to ensure each well maintains mechanical integrity at all times. The Director, by written notice, may require the permittee to comply with a schedule describing when mechanical integrity demonstrations shall be made.

(a) Notification. The Permittee shall notify the Director at least two (2) weeks prior to any required integrity test. The Director may allow a shorter notification period if it would be sufficient to enable the EPA to witness the mechanical integrity test. Notification may be in the form of a yearly or quarterly schedule of planned mechanical integrity tests (MIT), or it may be on an individual basis.

(b) Test Methods and Criteria. Test methods and criteria are to follow **current UIC Guidance for Conducting a Pressure Test to determine if a Well has leaks in the Tubing, Casing or Packer**. This guidance is found in **Appendix D**.

(c) Routine Demonstrations of Mechanical Integrity. The Permittee must demonstrate mechanical integrity by arranging and conducting a routine tubing/casing annulus pressure test at least one every five (5) years during the life of the facility and **after workovers** (see Part II. A. 5.). Results of the test shall be submitted (on EPA form found in **Appendix B**) to the Director as soon as possible but no later than sixty (60) days after the test is complete.

(d) Loss of Mechanical Integrity. If the well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity as defined by 40 CFR § 146.8 becomes evident during operation, the permittee shall notify the Director in accordance with Part III, Section E. 10. (c) of this permit. Furthermore, injection activities shall be terminated immediately; and operations shall not be resumed until the permittee has taken necessary actions to restore integrity to the well and the Director gives approval to recommence injection.

3. **Injection Interval.** Injection will be limited to the gross cased hole interval of the Nugget/Phosphoria/Tensleep Formations, 5202'- 6950'.

4. **Injection Pressure Limitation.**

(a) Injection pressure, measured at the surface, shall not exceed an amount that the Director determines is appropriate to ensure that injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to USDWs.

(b) The exact pressure limit may be increased or decreased by the Director in order to ensure that the requirements in paragraph (a) are fulfilled. In order to determine an exact pressure limit, the permittee shall conduct a step rate injection test or other authorized injection test(s) that will serve to determine the maximum fracture pressure (Pm) of the injection zone(s). Test procedures shall be pre-approved by the Director. The Director will specify in writing, to the permittee, any increase or decrease to the injection pressure based upon the test results and/or other parameters reflecting actual injection operations. Until such time that this demonstration is made, the initial maximum injection pressure (Pm), measured at the surface, **shall not exceed 1389 psig.**

5. **Injection Volume Limitation.** Effective on the date of the Final Permit there will be no limitation on the number of barrels of water per day (BWPD) that shall be injected into the Tribal S-1 well, provided further that in no case shall injection pressure exceed that limit shown in Part II. Section C. 4. (b) of this permit.

6. **Injection Fluid Limitation.** Injection fluids are limited to those which are brought to the surface in connection with natural gas storage operations, or conventional oil and gas production and may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection. Fluids shall be further limited to those

generated by sources owned or operated by the permittee.

7. **Annular Fluid.** The annulus between the tubing and the casing shall be filled with fresh water treated with a corrosion inhibitor, and a diesel freeze blanket may be circulated from surface to below frost level at completion to prevent freezing and possible equipment failure during winter months or other fluid as approved, in writing, by the Director.

D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. **Injection Well Monitoring Program.** Samples and measurements shall be representative of the monitored activity. The permittee shall utilize the applicable analytical methods described in Table 1 of 40 CFR §136.3, or in Appendix III of 40 CFR Part 261, or in certain circumstances, by other methods that have been approved by the Director. Monitoring shall consist of:

   (a) Analysis of the injection fluids, performed:

      (i) annually for Total Dissolved Solids, pH, Specific Conductivity, and Specific Gravity, from the common facility; however, if injection is maintained from more than one well from each common facility, then only one annual analysis is required for that facility; and

      (ii) whenever there is a change in the source of injection fluids a comprehensive water analysis shall be submitted to the Director within thirty (30) days of any change in injection fluids.

   (b) Monthly observations of flow rate, injection pressure, annulus pressure, and cumulative volume. One value for each of the above (**whether or not fluids are being injected**) shall be recorded at regular intervals no greater than thirty (30) days, and shall be representative of values obtained during operating conditions.

   A sudden change in either injection pressure and/or rate may also indicate another means of

determining mechanical integrity. If any leaks are detected, the well will be shut-in and corrective measures will be taken to restore integrity to the wellbore.

2. **Monitoring Information.** Records of any monitoring activity required under this permit shall include:

   (a) The date, exact place, the time of sampling or field measurements;

   (b) The name of the individual(s) who performed the sampling or measurements;

   (c) The exact sampling method(s) used to take samples;
   (d) The date(s) laboratory analyses were performed;

   (e) The name of the individual(s) who performed the analyses;

   (f) The analytical techniques or methods used by laboratory personnel; and

   (g) The results of such analyses.

3. **Recordkeeping.**

   (a) The permittee shall retain records concerning:

      (i) the nature and composition of all injected fluids until three (3) years after the completion of plugging and abandonment which has been carried out in accordance with the Plugging and Abandonment Plan shown in **Appendix C**, and is consistent with 40 CFR §146.10.

      (ii) all monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation and copies of all reports required by this permit for a period of at least five (5) years from the date of the sample, measurement or report throughout the operating life of the well.

   (b) The permittee shall continue to retain such records after the retention period specified in paragraphs (a) (i) and (a) (ii) unless he delivers the records to the Director or obtains written approval from the Director to discard the records.

(c) The permittee shall maintain copies (or the originals) of all pertinent records at the office of:

Marathon Oil Company
1501 Stampede Avenue
Cody, Wyoming

4. **Reporting of Results.** The permittee shall submit an Annual Report, whether injecting or not, to the Director summarizing the results of the monitoring required by Part II, Section D. 1. (a), and (b) of this permit.

The first Annual Report shall cover the period from the effective date of the permit through December 31. Subsequently, the Annual Report shall cover the period from January 1, through December 31. Annual Reports shall be submitted by February 15 of the following year following data collection. Appendix B contains Form 7520-11 which may be copied and used to submit the annual summary of monitoring.

E. PLUGGING AND ABANDONMENT

1. **Notice of Plugging and Abandonment.** The permittee shall notify the Director forty-five (45) days before conversion, or abandonment of the well.

2. **Plugging and Abandonment Plan.** The permittee shall plug and abandon the well as provided in the Plugging and Abandonment Plan, **Appendix C**. All plugs shall be "tagged" to verify plug placement. This plan incorporates information supplied by the permittee, and additional requirements specified by the EPA.

The Director reserves the right to change the manner in which the well will be plugged, if the well is modified during its permitted life, or if the well is not made consistent with EPA requirements for construction and mechanical integrity. The Director may ask the permittee to update the estimated plugging cost periodically. Such estimates shall be based upon costs which a third party would incur to plug the well according to the plan.

3. **Inactive Wells.** After a two (2) year period of injection inactivity, 40 CFR § 144.52 (a) (6), the

permittee shall plug and abandon the well in accordance with Paragraph 2 above, unless the permittee:

(a) Provides notice to the Director, including a demonstration that the well will be used in the future; and,

(b) Describes actions or procedures that the permittee will take to ensure that the well will not endanger USDWs during the period of inactivity. These actions and procedures shall include continuing Financial Responsibility and mechanical integrity demonstrations and maintaining compliance with permit requirements designed for the protection of USDWs; and,

(c) Receives written notice by the Director, temporarily waiving plugging and abandonment requirements.

4. **Plugging and Abandonment Report.** Within sixty (60) days after plugging the well, the permittee shall submit a report on Form 7520-13 (**Appendix B**) to the Director. The report shall be certified as accurate by the person who performed the plugging operation and the report shall consist of either:

(1) a statement that the well was plugged in accordance with the plan; or

(2) where actual plugging differed from the plan, a statement that specifies the different procedures followed.

F. FINANCIAL RESPONSIBILITY

1. **Demonstration of Financial Responsibility.** The permittee is required to maintain continuous financial responsibility and resources to close, plug, and abandon the injection well as provided in the plugging and abandonment plan.

(a) The permittee shall submit financial statements and other information annually, or as required by EPA, in order to demonstrate that its financial position remains sound, and that it continues to have adequate financial resources, as determined by the EPA, to close, plug, and abandon the injection well in accordance with the approved plugging and abandonment plan.

(b) The permittee may, upon his own initiative and upon written request to the Director, change the type of financial mechanism or instrument utilized. A change in demonstration of financial responsibility must be approved by the Director. A minor permit modification will be made to reflect any change in financial mechanisms, without opportunity for public comment.

2. **Insolvency of Financial Institution**. In the event that an alternate demonstration of financial responsibility has been approved under (b), above, the permittee must submit an alternate demonstration of financial responsibility acceptable to the Director within sixty (60) days after either of the following events occur:

(a) The institution issuing the trust or financial instrument files for bankruptcy; or

(b) The authority of the trustee institution to act as trustee, or the authority of the institution issuing the financial instrument, is suspended or revoked.

3. **Cancellation of Demonstration by Financial Institution**. If the institution issuing the trust or financial instrument serves, to the Director, a 120-day notice of their intent to cancel the trust or financial instrument, the permittee must submit an alternative demonstration of financial responsibility, acceptable to the Director, within sixty (60) days of such notice.

PART III. GENERAL PERMIT CONDITIONS

A. EFFECT OF PERMIT

The permittee is allowed to engage in underground injection in accordance with the conditions of this permit. The permittee, as authorized by this permit, shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR, Part 142 or otherwise adversely affect the health of persons. Any underground injection activity not authorized in this permit, or otherwise authorized by permit or rule, is prohibited. Issuance of this permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local law or regulations. Compliance with the terms of this permit does not constitute a defense to any enforcement action brought under the provisions of Section 1431 of the Safe Drinking Water Act (SDWA) or any other law governing protection of public health or the environment for any imminent and substantial endangerment to human health, or the environment, nor does it serve as a shield to the permittee's independent obligation to comply with all UIC regulations.

B. PERMIT ACTIONS

1. **Modifications, Reissuance, or Termination.** The Director may, for cause or upon a request from the permittee, modify, revoke and reissue, or terminate this permit in accordance with 40 CFR §§ 124.5, 144.12, 144.39, and 144.40. Also, the permit is subject to minor modifications for cause as specified in 40 CFR § 144.41. The filing of a request for a permit modification, revocation and reissuance, or termination or the notification of planned changes or anticipated noncompliance on the part of the permittee does not stay the applicability or enforceability of any permit condition.

2. **Conversions (Non-Class II).** The Director may, for cause or upon a request from the permittee, allow conversion of the well from a Class II injection well to a non-Class II well. Requests to convert the injection well from its Class II status to a non-Class II well, such as, a production well, must be made in writing to the Director. Conversion may not proceed until a permit modification indicating the conditions of the proposed conversion is received by the permittee. Conditions of the modification may include such items as, demonstration of mechanical integrity, and well specific monitoring and reporting following the conversion.

3. **Transfers.** This permit is not transferrable to any person except after notice is provided to the Director and the requirements of 40 CFR §144.38 are complied with. The Director may require modification, or revocation and reissuance, of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the SDWA.

4. **Operator Change of Address.** Upon the operator's change

of address, notice must be given to the appropriate EPA office.

C. SEVERABILITY

The provisions of this permit are severable, and if any provision of this permit or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit shall not be affected thereby.

D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and 40 CFR §144.5, any information submitted to EPA pursuant to this permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2 (Public Information). Claims of confidentiality for the following information will be denied:

- The name and address of the permittee, and
- Information which deals with the existence, absence or level of contaminants in drinking water.

E. GENERAL DUTIES AND REQUIREMENTS

1. **Duty to Comply.** The permittee shall comply with all conditions of this permit, except to the extent and for the duration such noncompliance is authorized by an emergency permit. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action, permit termination, revocation and reissuance, or modification. Such noncompliance may also be grounds for enforcement action under the Resource Conservation and Recovery Act (RCRA).

2. **Penalties for Violations of Permit Conditions.** Any person who violates a permit requirement is subject to civil penalties, fines, and other enforcement action under the SDWA and may be subject to such actions pursuant to the RCRA. Any person who willfully violates permit conditions may be subject to criminal

prosecution.

3. **Need to Halt or Reduce Activity not a Defense.** It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

4. **Duty to Mitigate.** The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.

5. **Proper Operation and Maintenance.** The permittee shall, at all times, properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit.

6. **Duty to Provide Information.** The permittee shall furnish the Director, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with the permit. The permittee shall also furnish to the Director, upon request, copies of records required to be kept by this permit.

7. **Inspection and Entry.** The permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

   (a) Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this permit;

   (b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

(c) Inspect, at reasonable times, any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and

(d) Sample or monitor, at reasonable times, for the purpose of assuring permit compliance or as otherwise authorized by the SDWA any substances or parameters at any location.

8. **Records of Permit Application.** The permittee shall maintain records of all data required to complete the permit application and any supplemental information submitted for a period of five (5) years from the effective date of this permit. This period may be extended by request of the Director at any time.

9. **Signatory Requirements.** All reports or other information requested by the Director shall be signed and certified according to 40 CFR §144.32.

10. **Reporting of Noncompliance.**

(a) Anticipated Noncompliance. The permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

(b) Compliance Schedules. Reports of compliance or noncompliance with or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted no later than thirty (30) days following each schedule date.

(c) Twenty four Hour Reporting.

(i) The permittee shall report to the Director any noncompliance which may endanger health or the environment. Information shall be provided orally within twenty-four (24) hours from the time the permittee becomes aware of the circumstances by telephoning EPA at **303.312.6485 (during normal business hours) or at 303.293.1788 (for reporting at all other times)**. The following information shall be included in the verbal report:

(A) Any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW.

(B) Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between underground sources of drinking water.

(ii) A written submission shall also be provided within five (5) days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

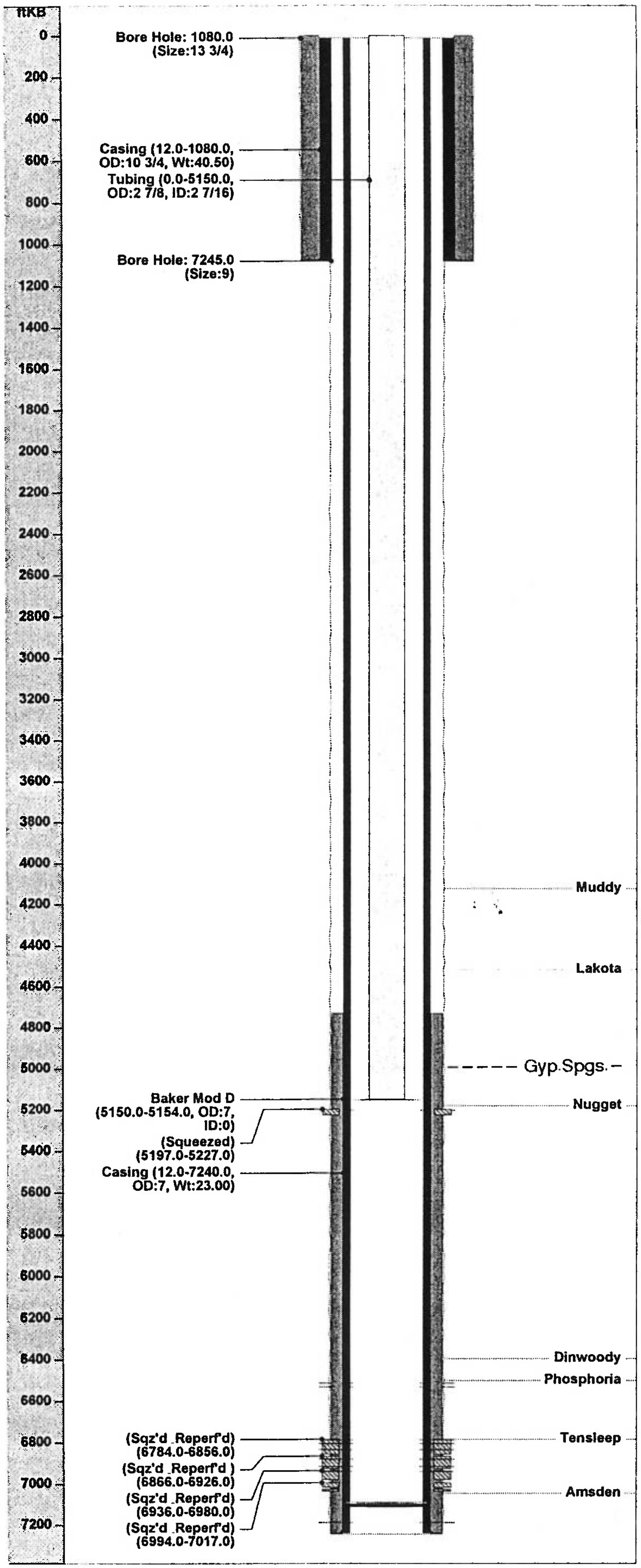
(d) Other Noncompliance. The permittee shall report all other instances of noncompliance not otherwise reported at the time monitoring reports are submitted. The reports shall contain the information listed in Part III, Section E. 10. (C) (ii) of this permit.

(e) Other Information. Where the permittee becomes aware that he failed to submit any relevant facts in the permit application, or submitted incorrect information in a permit application, or in any report to the Director, the permittee shall submit such correct facts or information within two (2) weeks of the time such information became known to him.

APPENDIX A

(Construction/Conversion Plans)

MARATHON OIL COMPANY



Tribal S-1 (Proposed)

API Code	49-013-06410	Field Code	
TD	7245.0 ftKB	Basin	
PBTD	7088.0 ftKB	Basin Code	
Operator	MOC	Permit	
State	Wyoming	Spud	2/18/49
County	Fremont	Finish Drl	8/1/49
Permit No.		Completion	8/1/49
TD Measured	7245'	Abandon	
Reservoir			
Field	STEAMBOAT BUTTE		

Location

Meridian	Wind River	Top Latitude	0
Twnship	3 North	Top Longitude	0
Range	1 West	Top NS Distance	
Section	333' FNL, 330' FEL Sec.6	Top EW Distance	
Quarter	NE NE NE Sec.6	Bottom Latitude	0
		Bottom Longitude	0
		Btm NS Distance	
		Btm EW Distance	

Elevations

KB	5734.0 ft	Cas Flng	
Grd	5722.0 ft	Tub Head	
KB-Grd	12.0 ft		

Casing String - Surface

Item (in)	Btm (ftKB)	Jnts	ID	Wt	Grd	Thd
10 3/4 in Casing	1080.0		10 3/64	40.50	H-40	

Casing String - Production

Item (in)	Btm (ftKB)	Jnts	ID	Wt	Grd	Thd
7 in Casing	7240.0		6 9/32	23.00	J-55 & N-80	

Casing Cement

Casing String	Top (ftKB)	Amount	Comments
Surface	0.0	700	Estimated
Production	4730.0	960	TOC (CBL - 1982)

Perforations

Date	Int	Zone	Shots (/ft)	Type
	5202.0 - 5232.0	Nugget	4.0	Proposed
	6514.0 - 6524.0	Phosphoria	4.0	Proposed
	6532.0 - 6538.0	Phosphoria	4.0	Proposed
11/1/87	6786.0 - 6790.0	Tensleep	4.0	Tensleep (Open)
11/1/87	6805.0 - 6814.0	Tensleep	4.0	Tensleep (Open)
11/1/87	6834.0 - 6858.0	Tensleep	4.0	Tensleep (Open)
11/1/87	6880.0 - 6916.0	Tensleep	4.0	Tensleep (Open)
11/1/87	6940.0 - 6950.0	Tensleep	4.0	Tensleep (Open)
8/29/49	7188.0 - 7194.0	Amsden	4.0	Ranchester (Isolated)

Tubing String - Injection Equipment

Item (in)	Top (ftKB)	Len (ft)	Jnts	ID (in)	Wt	Grd	Thd
2 7/8 in Tubing	0.0	5150.0	215	2 7/16	6.50	J-55	8-Rnd
7 in Baker Mod D	5150.0	4.0		0			

Other (plugs, equip., etc.) - Plug Back

Date	Item	Int (ftKB)
7/25/53	Baker Mod K (Junk)	7088.0 - 7093.0
1/4/51	2 sx Cement Plug w/5 gal gravel	7096.0 - 7110.0
1/4/51	Lane Wells BP	7110.0 - 7113.0

Stimulations & Treatments

Date	Type	tm.user	Int	tm.user	Comments
11/1/87	(Squeezed)		5197.0 - 5227.0		130 sx
10/1/82	(Sqz'd & Reperf'd)		6784.0 - 6856.0		150 sx class H
8/1/81	(Sqz'd & Reperf'd)		6866.0 - 6926.0		200 sx class G
8/1/81	(Sqz'd & Reperf'd)		6936.0 - 6980.0		200 sx class G
8/1/81	(Sqz'd & Reperf'd)		6994.0 - 7017.0		200 sx class G
8/1/81	(Sqz'd & Reperf'd)		7025.0 - 7036.0		200 sx class G

Formation/Horizon Tops

Top (ftKB)	TVD (ftKB)	Formation	Code	rm.user	Source
4123.0	4123.0	Muddy			
4518.0	4518.0	Lakota			
5180.0	5180.0	Nugget			
6395.0	6395.0	Dinwoody			
6500.0	6500.0	Phosphoria			
6784.0	6784.0	Tensleep			
7045.0	7045.0	Amsden			
5000	5000	Gyp.Spgs.			

Prepared by C.R. Adams 3/15/99

Exhibit #10b

APPENDIX C

(Plugging and Abandonment Plan)

Steamboat Butte Field Tribal S-1

Drill out BP at 7088'. Clean out to 7194'

PLUG NO. 1: Set a 131 sack cement plug from 7194' to 6450' across the Phosphoria, Tensleep and Amsden perforations.

PLUG NO. 2: Set a 27 sack cement plug across the Nugget perforations from 5300' to 5150'.

PLUG NO. 3: Perforate at 4730'. Squeeze 158 sacks of cement behind production casing to fill annulus from 4730' to 4000'. Run a temperature log to ensure that cement is covering the Lakota and Muddy. Set a 128 sack plug 4730' to 4000'.

PLUG NO. 4: Set an 18 sack cement plug from 1500' to 1400'.

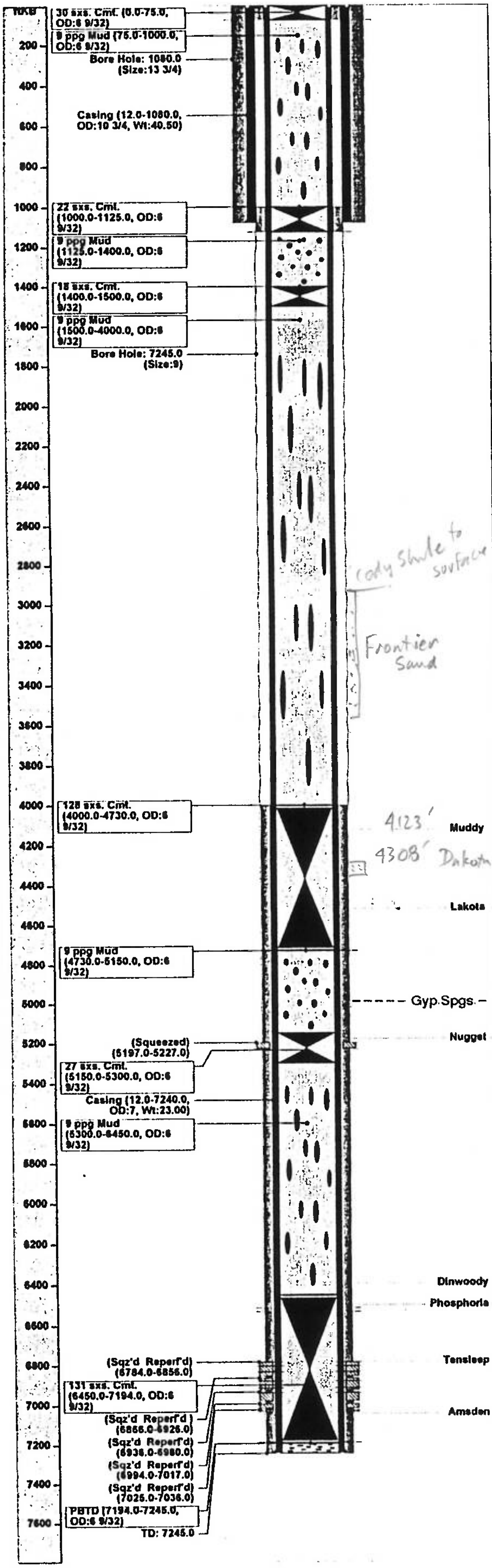
PLUG NO. 5: Perforate at 1125'. Squeeze 34 sacks into annulus and set 22 sacks in production casing from 1125' to 1000'

PLUG NO. 6: Perforate at 75'. Circulate 30 sacks of cement down the production casing and up the annulus to surface.

Set P&A marker and restore location.

NOTE: All PLUGS WILL BE TAGGED TO VERIFY PLUG PLACEMENT AND ALL CEMENT PLUGS WITHIN THE 7" CASING WILL BE SEPARATED BY 9.2 PPG BENTONITE MUD OR PLUGGING GEL.

M ATHON OIL COMPANY



Tribal S-1 (Proposed Plug and Abandonment Plan)

API Code	49-013-06410	Field Code	
TD	7245.0 ftKB	Basin	
PBTD		Basin Code	
Operator	MOC	Permit	
State	Wyoming	Spud	2/18/49
County	Fremont	Finish Drl	8/1/49
Permit No.		Completion	8/1/49
TD Measured	7245'	Abandon	
Reservoir			
Field	STEAMBOAT BUTTE		

Location

Meridian	Wind River	Top Latitude	0
Twnship	3 North	Top Longitude	0
Range	1 West	Top NS Distance	
Section	333' FNL, 330' FEL Sec.6	Top EW Distance	
Quarter	NE NE NE Sec.6	Bottom Latitude	0
		Bottom Longitude	0
		Btm NS Distance	
		Btm EW Distance	

Elevations

KB	5734.0 ft	Cas Flng	
Grd	5722.0 ft	Tub Head	
KB-Grd	12.0 ft		

Casing String - Surface

Item (in)	Btm (ftKB)	Jnts	ID	Wt	Grd	Thd
10 3/4 in Casing	1080.0		10 3/64	40.50	H-40	

Casing String - Production

Item (in)	Btm (ftKB)	Jnts	ID	Wt	Grd	Thd
7 in Casing	7240.0		6 9/32	23.00	J-55 & N-80	

Casing Cement

Casing String	Top (ftKB)	Amount	Comments
Production	0.0	30	Proposed PA Plan
Production	1000.0	34	Proposed PA Plan
Production	4000.0	158	Proposed PA Plan
Surface	0.0	700	Estimated
Production	4730.0	960	TOC (CBL - 1982)

Perforations

Date	Int	Zone	Shots (/ft)	Type
	5202.0 - 5232.0	Nugget	4.0	Proposed
	6514.0 - 6524.0	Phosphoria	4.0	Proposed
	6532.0 - 6538.0	Phosphoria	4.0	Proposed
	75.0 - 75.0		4.0	Proposed PA Plan
	1125.0 - 1125.0		4.0	Proposed PA Plan
	4730.0 - 4730.0	Lakota	4.0	Proposed PA Plan
8/29/49	7188.0 - 7194.0	Amsden	4.0	
11/1/87	6940.0 - 6950.0	Tensleep	4.0	
11/1/87	6880.0 - 6916.0	Tensleep	4.0	
11/1/87	6834.0 - 6858.0	Tensleep	4.0	
11/1/87	6805.0 - 6814.0	Tensleep	4.0	
11/1/87	6786.0 - 6790.0	Tensleep	4.0	

Other (plugs, equip., etc.) - Proposed PA Plan

Date	Item	Int (ftKB)
	30 sxs. Cmt.	0.0 - 75.0
	9 ppg Mud	75.0 - 1000.0
	22 sxs. Cmt.	1000.0 - 1125.0
	9 ppg Mud	1125.0 - 1400.0
	18 sxs. Cmt.	1400.0 - 1500.0
	9 ppg Mud	1500.0 - 4000.0
	128 sxs. Cmt.	4000.0 - 4730.0
	9 ppg Mud	4730.0 - 5150.0
	27 sxs. Cmt.	5150.0 - 5300.0
	9 ppg Mud	5300.0 - 6450.0
	131 sxs. Cmt.	6450.0 - 7194.0
	PBTD	7194.0 - 7245.0

Stimulations & Treatments

Date	Type	tm.user	Int	tm.user	Comments
11/1/87	(Squeezed)		5197.0 - 5227.0		130 sx
10/1/82	(Sqz'd & Reperf'd)		6784.0 - 6856.0		150 sx class H
8/1/81	(Sqz'd & Reperf'd)		6866.0 - 6926.0		200 sx class G
8/1/81	(Sqz'd & Reperf'd)		6936.0 - 6980.0		200 sx class G
8/1/81	(Sqz'd & Reperf'd)		6994.0 - 7017.0		200 sx class G
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6500.0	6500.0	Phosphoria			
6784.0	6784.0	Tensleep			
7045.0	7045.0	Amsden			
5000	5000	Gyp.Spgs.			

Prepared by C.R. Adams 3/15/99

Exhibit #12a

APPENDIX D

Guidance for Conducting a Pressure Test to Determine if a Well Has Leaks in the Tubing, Casing or Packer

UNITED S. .TES ENVIRONMENTAL PROTEC. JN AGENCY
REGION VIII
999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

SUBJECT: GROUND WATER SECTION GUIDANCE NO. 39
Pressure testing injection wells for Part I (internal) Mechanical Integrity

FROM: Tom Pike, Chief
UIC Direct Implementation Section

TO: All Section Staff
Montana Operations Office

Introduction

The Underground Injection Control (UIC) regulations require that an injection well have mechanical integrity at all times (40 CFR 144.28 (f)(2) and 40 CFR 144.51 (q)(1)). A well has mechanical integrity (40 CFR 146.8) if:

(1) There is no significant leak in the tubing, casing or packer; and

(2) There is no significant fluid movement into an underground source of drinking water (USDW) through vertical channels adjacent to the injection wellbore.

Definition: Mechanical Integrity Pressure Test for Part I. A pressure test used to determine the integrity of all the downhole components of an injection well, usually tubing,casing and packer. It is also used to test tubing cemented in the hole by using a tubing plug or retrievable packer. Pressure tests must be run at least once every five years. **If for any reason the tubing/packer is pulled, the injection well is required to pass another mechanical integrity test of the tubing casing and packer prior to recommencing injection regardless of when the last test was conducted. Tests run by operators in the absence of an EPA inspector must be conducted according to these procedures and recorded on either the attached form or an equivalent form containing the necessary information. A pressure recording chart documenting the actual annulus test pressures must be attached to the form.**

This guidance addresses making a determination of Part I of Mechanical Integrity (no leaks in the tubing, casing or packer). The Region's policy is: 1) to determine if there are significant leaks in the tubing, casing or packer; 2) to assure that the casing can withstand pressure similar to that which

<u>would be applied if the tubing or packer fails; 3) to make the Region's test procedure consistent with the procedures utilized by other Region VIII Primacy programs; and 4) to provide a procedure which can be easily administered and is applicable to all class I and II wells.</u> Although there are several methods allowed for determining mechanical integrity, the principal method involves running a pressure test of the tubing/casing annulus. Region VIII's procedure for running a pressure test is intended to aid UIC field inspectors who witness pressure tests for the purpose of demonstrating that a well has Part I of Mechanical Integrity. The guidance is also intended as a means of informing operators of the procedures required for conducting the test in the absence of an EPA inspector.

<u>Pressure Test Description</u>

<u>Test Frequency</u>

The mechanical integrity of an injection well must be maintained at all times. Mechanical integrity pressure tests are required <u>at least</u> every five (5) years. **If for any reason the tubing/packer is pulled, however, the injection well is required to pass another mechanical integrity test prior to recommencing injection regardless of when the last test was conducted. <u>The Regional UIC program must be notified of the workover and the proposed date of the pressure test.</u> The well's test cycle would then start from the date of the new test if the well passes the test and documentation is adequate.** Tests may be required on a more frequent basis depending on the nature of the injectate and the construction of the well (see Section guidance on MITs for wells with cemented tubing and regulations for Class I wells).

Region VIII's criteria for well testing frequency is as follows:

1. Class I hazardous waste injection wells; initially [40 CFR 146.68(d)(1)] and annually thereafter;

2. Class I non-hazardous waste injection wells; initially and every two (2) years thereafter, except for old permits (such as the disposal wells at carbon dioxide extraction plants which require a test at least every five years);

3. Class II wells with tubing, casing and packer; initially and at least every five (5) years thereafter;

4. Class II wells with tubing cemented in the hole; initially and every one (1) or two (2) years thereafter

depending on well specific conditions (See Region VIII UIC Section Guidance #36);

5. Class II wells which have been temporarily abandoned (TAd) must be pressure tested after being shut-in for two years; and

6. Class III uranium extraction wells; initially.

Test Pressure

To assure that the test pressure will detect significant leaks and that the casing is subjected to pressure similar to that which would be applied if the tubing or packer fails, the tubing/casing annulus should be **tested at a pressure equal to the maximum allowed injection pressure or 1000 psig whichever is less. The annular test pressure must, however, have a difference of at least 200 psig either greater or less than the injection tubing pressure. Wells which inject at pressures of less than 300 psig must test at a minimum pressure of 300 psig, and the pressure difference between the annulus and the injection tubing must be at least 200 psi.**

Test Criteria

1. The duration of the pressure test is 30 minutes.

2. Both the annulus and tubing pressures should be monitored and recorded every five (5) minutes.

3. If there is a pressure change of 10 percent or more from the initial test pressure during the 30 minute duration, the well has failed to demonstrate mechanical integrity and should be shut-in until it is repaired or plugged.

4. A pressure change of 10 percent or more is considered significant. If there is no significant pressure change in 30 minutes from the time that the pressure source is disconnected from the annulus, the test may be completed as passed.

Recordkeeping and Reporting

The test results must be recorded on the attached form. The annulus pressure should be recorded at five (5) minute intervals. Tests run by operators in the absence of an EPA inspector must be conducted according to these procedures and recorded on the attached form or an equivalent form and a pressure recording chart documenting the actual annulus test pressures must be attached to the submittal. The tubing pressure at the beginning and end of each test must be recorded. The volume of the annulus fluid bled back at the surface after the test should be measured and recorded on the form. This can be done by bleeding the annulus pressure off and discharging the associated fluid into a five gallon container. The volume information can be used to verify the approximate location of the packer.

Procedures for Pressure Test

1. Scheduling the test should be done at least two (2) weeks in advance.

2. Information on the well completion (location of the packer, location of perforations, previous cement work on the casing, size of casing and tubing, etc.) and the results of the previous MIT test should be reviewed by the field inspector in advance of the test. Regional UIC Guidance #35 should also be reviewed. Information relating to the previous MIT and any well workovers should be reviewed and taken into the field for verification purposes.

3. All Class I wells and Class II SWD wells should be shut-in prior to the test. A 12 to 24-hour shut-in is preferable to assure that the temperature of the fluid in the wellbore is stable.

4. Class II enhanced recovery wells may be operating during the test, but it is recommended that the well be shut-in if possible.

5. The operator should fill the casing/tubing annulus with inhibited fluid at least 24 hours in advance, if possible. Filling the annulus should be undertaken through one valve with the second valve open to allow air to escape. After the operator has filled the annulus, a check should be made to assure that the annulus will remain full. If the annulus can not maintain a full column of fluid, the operator should notify the Director and begin a rework. The operator should measure and report the volume of fluid added to the annulus. If not already the case, the casing/tubing valves should be closed, at least, 24 hours prior to the pressure test.

Following steps are at the well:

6. Read tubing pressure and record on the form. If the

well is shut-in, the reported information on the actual maximum operating pressure should be used to determine test pressures.

7. Read pressure on the casing/tubing annulus and record value on the form. If there is pressure on the annulus, it should be bled off prior to the test. If the pressure will not bleed-off, the guidance on well failures (Region VIII UIC Section Guidance #35) should be followed.

8. Ask the operator for the date of the last workover and the volume of fluid added to the annulus prior to this test and record information on the form.

9. Hook-up well to pressure source and apply pressure until test value is reached.

10. Immediately disconnect pressure source and start test time (If there has been a significant drop in pressure during the process of disconnection, the test may have to be restarted). The pressure gages used to monitor injection tubing pressure and annulus pressure should have a pressure range which will allow the test pressure to be near the mid-range of the gage. Additionally, the gage must be of sufficient accuracy and scale to allow an accurate reading of a 10 percent change to be read. For instance, a test pressure of 600 psi should be monitored with a 0 to 1000 psi gage. The scale should be incremented in 20 psi increments.

11. Record tubing and annulus pressure values every five (5) minutes.

12. At the end of the test, record the final tubing pressure.

13. If the test fails, check the valves, bull plugs and casing head close up for possible leaks. The well should be retested.

14. If the second test indicates a well failure, the Region should be informed of the failure within 24 hours by the operator, and the well should be shut-in within 48 hours per Headquarters guidance #76. A follow-up letter should be prepared by the operator which outlines the cause of the MIT failure and proposes a potential course of action. This report should be submitted to EPA within five days.

15. Bleed off well into a bucket, if possible, to obtain a volume estimate. This should be compared to the calculated value obtained using the casing/tubing annulus volume and fluid compressibility values.

16. Return to office and prepare follow-up.

Alternative Test Option

While it is expected that the test procedure outlined above will be applicable to most wells, the potential does exist that unique circumstances may exist for a given well that precludes or makes unsafe the application of this test procedure. In the event that these **exceptional or extraordinary** conditions are encountered, the operator has the option to propose an alternative test or monitoring procedures. The request must be submitted by the operator in writing and must be approved in writing by the UIC-Implementation Section Chief or equivalent level of management.

Attachment

Mechanical Integrity Test
Casing or Annulus Pressure Mechanical Integrity Test

U.S. Environmental Protection Agency
Underground Injection Control Program, UIC Direct Implementation Program 8P-W-GW
999 18th Street, Suite 500 Denver, CO 80202-2466

EPA Witness: ______________________________ Date: ____/____/____
Test conducted by: ______________________________
Others present: ______________________________

Well Name: ______________________ Type: ER SWD Status: AC TA UC
Field: ______________________
Location: ________ Sec: ____ T ____ N / S R ____ E / W County: ____________ State: ___
Operator: ______________________
Last MIT: ____/____/____ Maximum Allowable Pressure: ______________ PSIG

Is this a regularly scheduled test? [ ] Yes [ ] No
Initial test for permit? [ ] Yes [ ] No
Test after well rework? [ ] Yes [ ] No
Well injecting during test? [ ] Yes [ ] No If Yes, rate: ____________ bpd

Pre-test casing/tubing annulus pressure: ______________ psig

MIT DATA TABLE	Test #1	Test #2	Test #3
TUBING PRESSURE			
Initial Pressure	psig	psig	psig
End of test pressure	psig	psig	psig
CASING / TUBING ANNULUS PRESSURE			
0 minutes	psig	psig	psig
5 minutes	psig	psig	psig
10 minutes	psig	psig	psig
15 minutes	psig	psig	psig
20 minutes	psig	psig	psig
25 minutes	psig	psig	psig
30 minutes	psig	psig	psig
minutes	psig	psig	psig
minutes	psig	psig	psig
RESULT	[ ] Pass [ ]Fail	[ ] Pass [ ]Fail	[ ] Pass [ ]Fail

Does the annulus pressure build back up after the test ? [ ] Yes [ ] No

(over)

STATEMENT OF BASIS

MARATHON OIL COMPANY

TRIBAL S-1
STEAMBOAT BUTTE FIELD
CLASS II ENHANCED OIL RECOVERY

FREMONT COUNTY, WYOMING

EPA PERMIT NUMBER: WY2866-02130

CONTACT: Chuck Williams
U. S. Environmental Protection Agency
UIC Section, 8P-W-GW
999 18th Street, Suite 500
Denver, Colorado 80202-2466
Telephone: 303.312.6625

DESCRIPTION OF FACILITY AND BACKGROUND INFORMATION:

On March 24,1999, Marathon Oil Company (Marathon), Cody, Wyoming made application for an underground injection control (UIC) permit converting the well in question from a Tensleep injector to a commingled Nugget, Phosphoria and Tensleep formation injection well to support an ongoing secondary recovery project in the Steamboat Butte Field. Injected waters will be a combination of produced waters (total dissolved solids [TDS] content of approximately 3,610 mg/l, Mission Pond Injection Plant, sampled November 23, 1998) from all producing formations in the Steamboat Butte Field.

The Tribal S-1 is currently an Authorized by Rule Tensleep Formation enhanced recovery well. Major construction changes to a well Authorized by Rule require permitting as cited in 40 CFR § 144.25 (a). (2), Requiring a Permit, and 40 CFR § 144.31 (c), Time to Apply. The Marathon Oil Company (Marathon) application for Permit is to add the Nugget and Phosphoria Formations as an enhanced recovery injection well, i.e.,major construction.

The area covered by the application is in a portion of the Steamboat Butte Field, and contained within the exterior Boundaries of the Wind River Indian Reservation and the well location is defined as follows:

Tribal S-1

NE/4 NE/4 Section 6, Township 4 North, Range 1 West
Fremont County, Wyoming

The Tensleep and Phosphoria Formations in the Steamboat Butte Field area, in accordance with 40 CFR § 147.2554, those portions of aquifers currently being used for injection in connection with Class II (oil and gas) injection operations on the Wind River Reservation are exempted for the purpose of Class II injection operations. The Nugget Formation, with a total dissolved content (TDS) of 16,833 mg/l is not considered a USDW.

Underground sources of drinking water (USDWs) are defined by the UIC regulations as aquifers or portions thereof which contain more then 3000 mg/l and less than 10,000 mg/l total dissolved solids (TDS) and which are being or <u>could</u> be used as a source of drinking water. Known USDWs in the general area have been identified by the State of Wyoming Oil and Gas Conservation Commission (May 8, 1991) as the:

FORMATION	**DEPTH (feet)**	**WATER QUALITY (mg/l)**
Quaternary sands	not present	2430
Wind River sands	not present	700 - 2800
Cody shale (thin isolated sands)	0 - 2883	1750 - 2430
Frontier sand	2883 - 3580	4383 - 7630
Muddy sand	4123 - 4151	7292 - 7553
Dakota sand	4308 - 4383	6080

Other than near-surface gravels, any USDWs in the general area of the well, including the Phosphoria and Tensleep Formations, are all behind the long string casing which is cemented up to a depth of 1,982 feet (TOC per CBL); 3,220 feet above top Nugget perforations.

All possible USDW intervals encountered in the Tribal S-1 well are currently producing hydrocarbons in this area. The Frontier, Muddy and the Dakota sands are all producing in the Steamboat Butte Field and the discontinuous sand lenses in the Cody shale have hydrocarbon shows and are productive in the nearby Pilot Butte Field.

The Tensleep Formation, with a water quality of 5,861 mg/l TDS, and the Phosphoria Formation with a TDS of 7,347 mg/l were granted field wide exempted aquifer status under CFR 40 § 147.2554, October 25, 1988. The TDS of the Nugget Formation is found to be 16,833 mgl/l and not considered to be a USDW. The limits of the exempted aquifers include those portions of the aquifers defined on the surface by an outer boundary of those quarter-quarter sections dissected by a line drawn parallel to, but one-quarter mile outside, the Steamboat Butte Field boundary.

The **confining zone** (5000'- 5180') above the Nugget Formation, the uppermost injection interval, is composed of 180' of Gypsum Springs Formation that consists of impermeable interlayered anhydrite, shaley limestone, dense dolomite, siltstone, and red shale near the base of the formation. This facies will prevent upward migration of injected water and serve as a safeguard against contamination of shallow aquifers.

Marathon has submitted all required information and data necessary for permit issuance in accordance with 40 CFR §§ 144, 146 and 147, and a draft permit has been prepared.

The permit will be issued for the life of the well from the effective date of the permit. During the life of the well, no reapplication will be necessary, unless the permit is terminated for reasonable cause (40 CFR §§ 144.39, 144.40 and 144.41). However, the permit will be reviewed every five (5) years.

This Statement of Basis gives the derivation of the site-specific permit conditions and reasons for them. The general permit conditions for which the content is mandatory and not subject to site-specific differences (based on 40 CFR §§ 144, 146 and 147), are not included in the discussion.

PART II, Section A WELL CONSTRUCTION REQUIREMENTS

Casing and Cementing (Condition 1)

A casing and cementing plan was submitted with the permit application. For the injection well, drilled and completed as a Ranchester (Darwin) Formation producer February, 1949, construction is as follows:

(1) 10 3/4" **surface casing** is set in a 13-3/4" inch diameter hole to a depth of 1080' kelly bushing (KB). The cement (700 sacks) used to secure the casing was circulated to the surface, isolating the casing from the wellbore.

(2) The well was drilled to a total depth (TD) of 7240' using a 9" diameter bit. **Production casing** (7") was run in the hole to a depth of 7240' and cemented with 960 sacks of Class "G" cement from 4730'-7240', per cement bond log (CBL) run 10/4/82.

The well was worked over in 1950, resulting in a Tensleep producer, with the Ranchester perforations isolated below a bridge plug. The well produced as a Tensleep producer until December, 1982, when it was recompleted as a Nugget producer, with the Tensleep cement squeezed below a cement retainer. The well produced as a Nugget producer until December, 1987, when it was recompleted as a Tensleep injector with the Nugget perforations cement squeezed.

The **Tribal S-1** well has been in operation as a Tensleep Formation injection well since December, 1987, (prior to November 25, 1988, effective date of the UIC program on Indian lands in Wyoming). This well is currently authorized by rule, (40 CFR §§ 144.21 (c) and 144.22 (b), therefore, until final issuance of this permit, authorized by rule will end and operation of the well will be governed by conditions specified in this permit.

UPON REENTRY OF THIS SHUT-IN TENSLEEP FORMATION INJECTION WELL, THE CONVERSION TO A COMMINGLED NUGGET/PHOSPHORIA/TENSLEEP ENHANCED OIL RECOVERY WELL WILL BE AS FOLLOWS:

The proposed procedure will consist of perforating the Nugget (5202'-5232'), and the Phosphoria (6514'-6524-6538'). The Nugget will be stimulated with a small sand frac. A 7" Baker packer (or equivalent) will be run in the well and set at an approximate depth of 5150'. Approximately 5150' of 2-7/8" injection tubing will be run to surface above the packer. The wellbore annulus above the packer will be filled with a fluid composed of fresh water treated with corrosion inhibitors and oxygen scavengers. Test well for mechanical integrity (MIT), according to current UIC Guidance found in **Appendix D**, if passed, place well on injection status and wait upon written approval from EPA to start injection. **A Water injection profile log will be run on the well as soon as stabilized injection is established.**

Tubing and Packer Specifications (Condition 2)

Injection tubing and packer shall be designed to prevent injected fluids from coming into contact with the outermost casing string. The packer shall be set at a depth of no more than 100 feet above the top perforations. The presence of an annular space between the tubing and casing allows the casing integrity to be periodically tested, as well as to monitor for leaks in the tubing.

Monitoring Devices (Condition 3)

The operator shall provide and maintain in good operating condition:

(a) a tap on the injection line between the pump house and the storage tank(s) and the injection well, for collection of a representative sample of injection fluids;

(b) two (2) one-half (½) inch Female Iron Pipe (FIP) fittings with cut-off valves, one at the wellhead on the tubing, and a similar fitting and cut-off valve for the casing/tubing annulus (for attachment of pressure gauges). The operator shall always have in his possession calibrated gauges for the use of their field personnel to monitor these pressures.

(c) a flow meter with a cumulative volume recorder that is certified for 95 percent accuracy or more throughout the range of injection rates allowed by the permit.

If any leaks are detected, the well will be shut-in and corrective measures will be taken to restore integrity to the wellbore.

Formation Logging and Well Testing (Condition 5)

(a) Following the conversion of **Tribal S-1**, the permittee is required to determine the injection zone fluid pore pressure (**static bottom-hole pressure**).

(b) **A water injection profile log** will be run as soon as stabilized injection pressure has been established. This test will be used to assure no out of zone injection is occurring - should the test identify movement of injected fluids above the top Nugget perforations, injection shall be discontinued immediately until remedial work, approved by the EPA, is performed.

PART II, Section B CORRECTIVE ACTION

The applicant submitted the required 1/4 mile area of review information with the permit application. Listed are six (6) producing wells, (1-Frontier, 3-Nugget, 2-Tensleep), and one (1) Class II permitted and commingled well (Phosphoria/Tensleep), and one (1) Class II Rule Authorized injection well (subject well). In each of these wells, the production/wellbore annulus is cemented from the top of the Frontier, upward and several hundred feet into the overlying Cody shale (confining zone) and the underlying thick (535 feet) Mowry shale. All wells, but the recently permitted Tribal C-28, are adequately constructed to preclude USDW contamination via injection into the Phosphoria and Tensleep Formations; therefore, the only corrective action required (perforate and block squeeze Phosphoria) is on the recently permitted Tribal C-28 well.

PART II, Section C WELL OPERATION

Prior to Commencing Injection (Condition 1)

Injection operations shall not commence until the permittee has complied with the following:

a. Conversion is complete and the permittee has submitted a **Well Rework Report (EPA Form 7520-12).**

b. **Static bottom-hole pressure of injection zone has been determined.**

c. A successfully passed **mechanical integrity test (MIT)** has been performed and witnessed according to the current guidance found in **Appendix D.** The permittee shall notify the EPA two (2) weeks prior to conducting this test so that an authorized representative may be present to witness the tests; and

Mechanical Integrity (Condition 2)

A demonstration of mechanical integrity must be made, prior to the start of injection, to verify that the tubing/casing/packer system will not leak. Specific criteria for mechanical integrity testing is outlined in the permit found in **Appendix D.** (current UIC Guidance for Conducting a Pressure Test).

In addition to the original MIT, a tubing/casing annulus pressure test must be repeated at least once every five (5) years to demonstrate continued tubing, packer, and casing integrity.

Injection Interval (Condition 3)

Injection will be limited to the gross cased hole interval of the Nugget/Phosphoria/Tensleep Formations, 5202'- 6950'.

Injection Pressure Limitation (Condition 4)

Injection pressure (Pm), measured at the surface, shall not exceed an amount that the Director determines is appropriate to ensure that injection does not initiate new fractures or propagate existing fractures in the confining zone overlying the injection zones. Enclosed with the permit application is a copy of EPA's "Acceptable Sand-Face Fracture Gradients" for the Steamboat Butte Field, date August 12, 1997. The data provided by Chevron U.S.A. Production Company, (previous owner of the field) was from Step-Rate tests and ISIP information for three producing zones in the Steamboat Butte Field. Given these conditions, the maximum surface injection pressure (Pm) for the Nugget, Phosphoria and Tensleep are as follows for:

NUGGET:

$$Pm = [0.70 - 0.433\ (Sg)]\ d$$

Where: Pm = maximum pressure at wellhead
SG = specific gravity of composite mixture of Produced water = 1.00
d = depth to injection zone = 5202'

or Pm = [0.77 - 0.433 (1.00)] 5202

Pm = 1389 psig

PHOSPHORIA:

Pm = [0.77 - 0.433 (Sg)] d

Where: Pm = maximum pressure at wellhead
Sg = specific gravity of composite mixture of produced water = 1.00
d = depth to injection zone = 6514 feet

or Pm = [0.77 - 0.433 (1.00)] 6514

Pm = 2195 psig

TENSLEEP:

Pm = [0.70 - 0.433 (Sg)] 6786

Pm = 1812 psig

The anticipated average and maximum injection pressure for the **Tribal S-1** will be 1300 and 1389 psig respectively. Therefore, the maximum injection pressure (Pm) will be the lessor of the three injection zones, or **1389 psig** as calculated for the Nugget Formation; if a higher maximum surface injection pressure is requested it must be accompanied by a step-rate test (SRT) of the injection zone(s)

Injection Volume Limitation (Condition 5)

Effective on the date of the Final Permit there will be no limitation on the number of barrels of water per day (BWPD) that shall be injected into the **Tribal S-1** well, provided further that in no case shall injection pressure exceed that limit shown in Part II. Section C. 4. (b) of this permit. The injection fluid is limited to produced brine from wells within the Steamboat Butte Field further limited to those generated by sources owned or operated by the permittee.

PART II, Section D MONITORING, RECORDKEEPING AND REPORTING OF RESULTS

Injection Well Monitoring Program (Condition 1)

The permittee is required to monitor water quality of the injected fluids on an annual basis. A water sample of injected fluids shall be analyzed for total dissolved solids, pH, specific conductivity, and specific gravity. Any time there is a change in the source of injection fluid, a new water quality analysis is also required.

In addition, monthly observations of flow rate, injection pressure, annulus pressure and cumulative volume will be made. At least one observation of each (whether or not fluids are being injected) shall be recorded at regular intervals no greater than thirty (30) days, and shall be representative of values obtained during operating conditions.

PART II, Section E PLUGGING AND ABANDONMENT

Plugging and Abandonment Plan (Condition 2)

The plugging and abandonment plans submitted by the applicant, are incorporated into the permit, (**Appendix C** of the permit) and shall be binding on the permittee. These plans have been reviewed by the EPA and are consistent with UIC requirements.

PART II, Section F FINANCIAL RESPONSIBILITY

Demonstration of Financial Responsibility (Condition 1)

The permittee has chosen to demonstrate financial responsibility through a Financial Statement that has been reviewed and approved by the EPA.

Technical Review Checklist

UIC Injection Well Permit

Operator Marathon Oil OPID MAR04
Well Tribal S-1 Permit No. WY2866-02130
Field Steamboat Butte API No. 49-013-06410
Location: (QTR/QTR) NE/NE Sec: 6 T 4 N/S R 1 E/W County Fremont State WY

AREA OF REVIEW

Number of wells in AOR 8 Number Needing Corrective Action 1 - Recently Permitted
1/4 mile or Other (& method) ______

GEOLOGY

USDW Name See SOB pg. 2	Top	Bottom	TDS
USDW Name	Top	Bottom	TDS
USDW Name	Top	Bottom	TDS
USDW Name	Top	Bottom	TDS
USDW Name	Top	Bottom	TDS
Confining Zone Name Gypsum Springs	Top 5005'	Bottom 5180'	
Injection Zone Name Nugget/Phos/Ten.	Top 5202'	Bottom 6950'	TDS 7347 mg/l 5861

WELL CONSTRUCTION

Total Depth 7245 Surface Casing Depth 1080' Packer ± 5150' TOP Perf 5202'
Top of adequate (80%) cement ______ Top of Cement 4730'
☒ CBL or ☐ Calculated

OPERATION

Maximum Injection Pressure 1389 PSIG
Injection Fluid: Type Prod. Wtr. TDS 3,610 mg/l

FINANCIAL RESPONSIBILITY

Amount: $40,000 Type of Instrument: Fin. Statement
The following items must be addressed:

______

Permit Writer Chuck Williams